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Reservoir Mechanics of Geopressured Aquifers

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ABSTRACT

To evaluate the practicality of producing energy from geopressured aquifers, methods to predict energy-production rates are necessary. This paper reviews established petroleum-reservoir engineering techniques as applied to geopressured systems. Also, the effects of dissolved natural gas, shale water influx, and abnormally high rock compressibilities on aquifer behavior are discussed.

DISCUSSION

Before geopressure resources can be exploited, methods to predict power production from specific aquifers are necessary. Power production is directly related to the flow rate of the water, its surface flowing pressure, its surface temperature, its complement of dissolved methane, and the efficiency of conversion of this source of energy to a more usable form, such as electricity. This paper presents methods of predicting volumes and surface pressures of the produced water. Some pertinent thoughts about the effect, if any, of dissolved methane are also presented. The conversion of hydraulic, thermal, and natural-gas energy to more usable forms is not considered here.

All of the equations and concepts presented are derived from well-established theory and equations of petroleum-reservoir engineering. Much of the work here was originally presented by Parmigiano (1973) in a master's thesis at Louisiana State University. All calculation methods given apply to bounded aquifers for the following cases: (1) an aquifer containing a single well; (2) an aquifer containing multiple wells, with all wells being in a centrally positioned cluster; and (3) an aquifer containing multiple wells, with all wells being uniformly spaced throughout. Sample calculations are given for the first case, and simple-to-use equations are given for the other two cases. The sample calculations utilize the hypothetical data of table 1.

All prediction methods presented are valid for the so-called constant terminal rate case, which means the rates of the wells are constant for a period of time while flowing pressures change with time. At the end of a specified length of time, well rates can be changed to any other constant flow rate. As will be seen, well rates can be changed at arbitrary, short intervals, thereby providing prediction methods for virtually any situation. Calculations for frequent rate changes increase in complexity, however, and are best handled by computers.

SINGLE-WELL CASE

The single-well case consists of a single well located in the center of a bounded aquifer. The aquifer is assumed to be either circular or square in shape, depending on which of the following two prediction methods is used.

Rigorous Method

This solution, the *Ei* solution, (see Craft and Hawkins (1959) for details) provides for a completely rigorous treatment of the pressure-time relationship of a well flowing at a constant rate in an infinite system. The major assumptions inherent in the solution are (1) constant porosity, permeability, and sand thickness throughout the aquifer; (2) water viscosity is independent of pressure; and (3) the effective compressibility of the system (water + rock) is

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independent of pressure. As will be shown, the restrictions of constant flow rate and infinite aquifer size can be removed by the application of the principle of superposition. The *Ei* solution has the following form for predicting the downhole flowing pressure, p_f.

$$p_f = p_i + \frac{q\mu}{14.16kh}\; Ei\left(-\;\frac{25.3\phi\mu c_e r_w^2}{kt}\right) \tag{1}$$

The units used in this and all other equations are given in the nomenclature. As shown by Craft and Hawkins (1959), this equation can be closely approximated by

$$p_f = p_i - \frac{q\mu}{7.08kh}\; ln\left(\frac{14.22kt}{\mu c_e \phi r_w^2}\right) \tag{2}$$

Because the flowing pressure at the surface is of importance in the utilization of geohydraulic power, equation 2 must be altered to account for the loss in pressure between the bottom of the well and the surface. This loss in pressure is the sum of the frictional pressure loss in flowing up the well and the static head loss. The surface flowing pressure (tubing head pressure), p_{tf}, is

$$p_{tf} = p_i - \frac{q\mu}{7.08kh}\; ln\left(\frac{14.22kt}{\mu c_e \phi r_w^2}\right) - \Delta p_f - \Delta p_h. \tag{3}$$

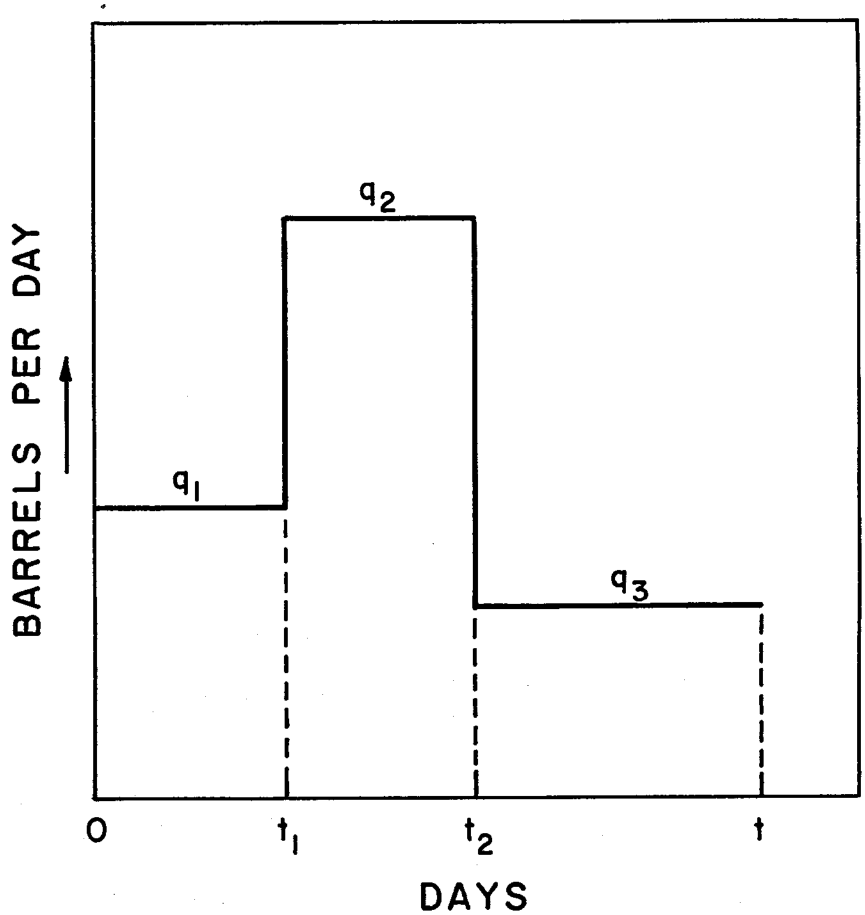

Figure 1. Production history of a well, showing stepwise rate history.

The principle of superposition can be utilized to account for changing flow rates. For example, suppose the pressure-time relationship is desired for the flow rate-time relationship shown in figure 1. The following equation predicts the flowing surface pressure at time t.

$$
\begin{aligned}
p_{tf} = {} & \frac{q_1\mu}{14.16kh}\ ln\left(\frac{14.22kt}{\phi\mu c_e r_w^2}\right) \\
& + \frac{(q_2 - q_1)\mu}{14.16kh}\ ln\left[\frac{14.22k(t - t_1)}{\phi\mu c_e r_w^2}\right] \\
& + \frac{(q_3 - q_2)\mu}{14.16kh}\ ln\left[\frac{14.22k(t - t_2)}{\phi\mu c_e r_w^2}\right] - \Delta p_f - \Delta p_h.
\end{aligned} \tag{4}
$$

In order to remove the mathematical restriction of having an infinite reservoir, superposition is once again utilized. Image wells are used to change the infinite system to a square, bounded system. Theoretically, an infinite number of image wells are required, as indicated in figure 2. Practically, several rows of image wells are usually sufficient to create the boundaries. For a well producing at a constant rate in a square aquifer, the pressure is predicted at time t as

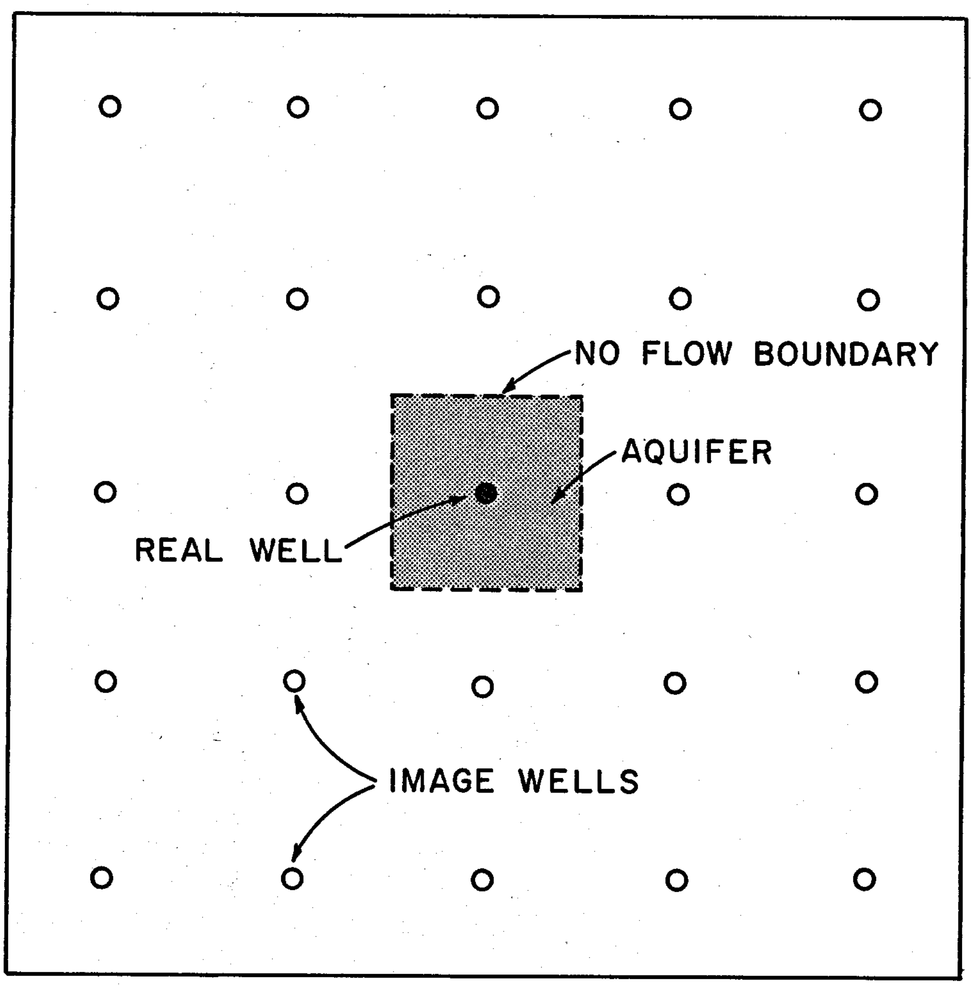

Figure 2. Image wells to simulate a square, bounded aquifer.

$$p_{tf} = p_i - \frac{q\mu}{7.08kh} \ ln \left(\frac{14.22kt}{\mu c_e \phi r_w^2}\right)$$
$$+ \frac{q\mu}{14.16kh} \sum_{i=1}^{n} \ Ei \left(- \frac{25.3\phi\mu c_e d_i^2}{kt}\right) - \Delta p_f - \Delta p_h, \quad (5)$$

where the summation of the *Ei* terms represents the contribution of the *n* image wells. The term d_i is the distance between the i^{th} image well and the real well. The values of *Ei* function can be obtained from published tables.

If the prediction of pressure for a single well with changing flow rates is desired for a bounded aquifer, then a combination of the two types of superposition (eqs. 4 and 5) must be utilized. Note that the image wells must all experience the same rate changes as the real well. Hand calculations are practically ruled out because of the extremely large number of computations; computer programs are available to perform the calculations.

To illustrate the use of this method consider the following hypothetical problem. A geopressured aquifer has been exploited by a single well in the center of the square, bounded area. The well will be produced at 100,000 barrels per day until the surface flowing pressure reaches 2,000 psi. At this time, the rate will be curtailed to 80,000 barrels per day so that the surface pressure will once again rise higher than 2,000 psi. The rationale behind this is that when turbines are developed to harness the geohydraulic power, they will probably require some minimum inlet pressure. It is merely conjectured for this sample problem that this minimum pressure will be 2,000 psi. The reservoir, well, and fluid data for this problem are given in table 1. For the specific case of a 12,000-foot well and 9-inch ID pipe, the frictional pressure loss can be expressed as

$$\Delta p_f = 8.8 \times 10^{-8} q^{1.9} \quad (6)$$

and is derived from the routinely used Fanning friction curves (Craft and others, 1962).

TABLE 1

Aquifer, Well, and Fluid Data for the Hypothetical Problem

Pipe diameter (ID) = 9 inches	Permeability = 0.1 darcy
Initial pressure = 10,000 psig	Thickness = 200 feet
Temperature = 300°F	Wellbore radius = 0.375 feet
Water viscosity = 0.3 cp	Compressibility = 10^{-5} psi^{-1}
Porosity = 20 percent	Depth = 12,000 feet
Water density = 1.0 g/cc	Aquifer size = 200,000 acres
	= 312 square miles

The results of the calculations, which were done by computer, are shown in figure 3 and in table 2. In all calculations the loss in pressure due to the static head is

$$\Delta p_h = 12,000 \times 0.433 = 5,196 \text{ psi.}$$

The pressure loss due to friction is 280 psi for the 100,000-barrel-per-day rate and 185 psi for the 80,000-barrel-per-day rate, as calculated from equation 6.

TABLE 2

Solution to Sample Problem
(Rigorous Method)

Time, Days	Flow Rate, Barrels per Day	Surface Pressure, PSIG
1	100,000	2,761
10	100,000	2,517
100	100,000	2,274
500	100,000	2,102
800	100,000	2,043
1,056	100,000	2,000
1,057	80,000	2,447
1,060	80,000	2,476
1,080	80,000	2,511
1,100	80,000	2,520
1,200	80,000	2,529
1,500	80,000	2,504
2,000	80,000	2,443
3,000	80,000	2,314
4,000	80,000	2,185
5,000	80,000	2,057

The surface flowing pressure is 2,761 psi after the first day of production and steadily declines until it reaches the arbitrary cutoff of 2,000 psi at 1,056 days (2.9 years). At this time, well rate is curtailed to 80,000 barrels per day, the surface pressure rises to 2,447 psi after the first day and remains above 2,000 psi for an additional 4,384 days (12 years). The well has thus been above 2,000 psi for a total of 5,440 days (14.9 years). At this time, the well rate can again be curtailed to increase the surface pressure. This stepwise rate reduction can be repeated until the flow rate becomes so small that the power output reaches the economic limit. Theoretically, the aquifer could be produced until the average pressure in the aquifer reached the level of the hydrostatic head, 5,196 psi. Practically, the aquifer would be abandoned long before this. In this hypothetical example, less than 1 percent of the water in place and the energy in place will have been removed from the aquifer at the end of 14.9 years, and less than one-fourth of the energy removed from the aquifer reaches the surface due to the pressure losses of overcoming flow friction and static head. Note that this does not consider the conversion efficiency of the surface facility. Average aquifer pressure will be 9,265 psi at this time.

Approximate Solution

Parmigiano (1973) developed methods for predicting the performance of wells completed in geopressured aquifers. Among the equations he developed is the following one for the surface pressure of a single well completed in the center of a bounded, circular aquifer.

$$p_{tf} = p_i - \frac{q\mu}{7.08kh}\left[ln\,(r_e/r_w) - 0.75\right] - \frac{5.615Q}{\pi r_e^2 h\phi c_e} - \Delta p_f - \Delta p_h. \qquad (7)$$

This equation is valid only when the aquifer has reached semi-steady-state conditions, which means that pressures are falling everywhere throughout the aquifer at the same rate. Semi-steady-state conditions are not reached until there has been flow at a constant rate for a period of time given by

$$t_s = \frac{0.04\mu c\phi r_e^2}{k} \tag{8}$$

Therefore, when the well is first put on production and whenever the well rate changes, equation 7 will yield erroneous answers until a time equal approximately to t_s has elapsed.

The first negative term of equation 7 is the frictional pressure loss in the aquifer itself because of flow, and is a form of Darcy's law. The second negative term is the drop in average aquifer pressure owing to production of fluid.

Application of the equation to the data of the hypothetical problem yields the results presented in figure 3. Since this method assumes a circular aquifer, an external radius, r_e can be approximated by a circle of the same area as the square aquifer used in the previous calculations. In this case, r_e is 52,800 feet. The pressure predicted by this approximate method is lower than those predicted by the theoretical method, but, practically speaking, the difference is not great. The calculations are very simple and can be made easily by hand.

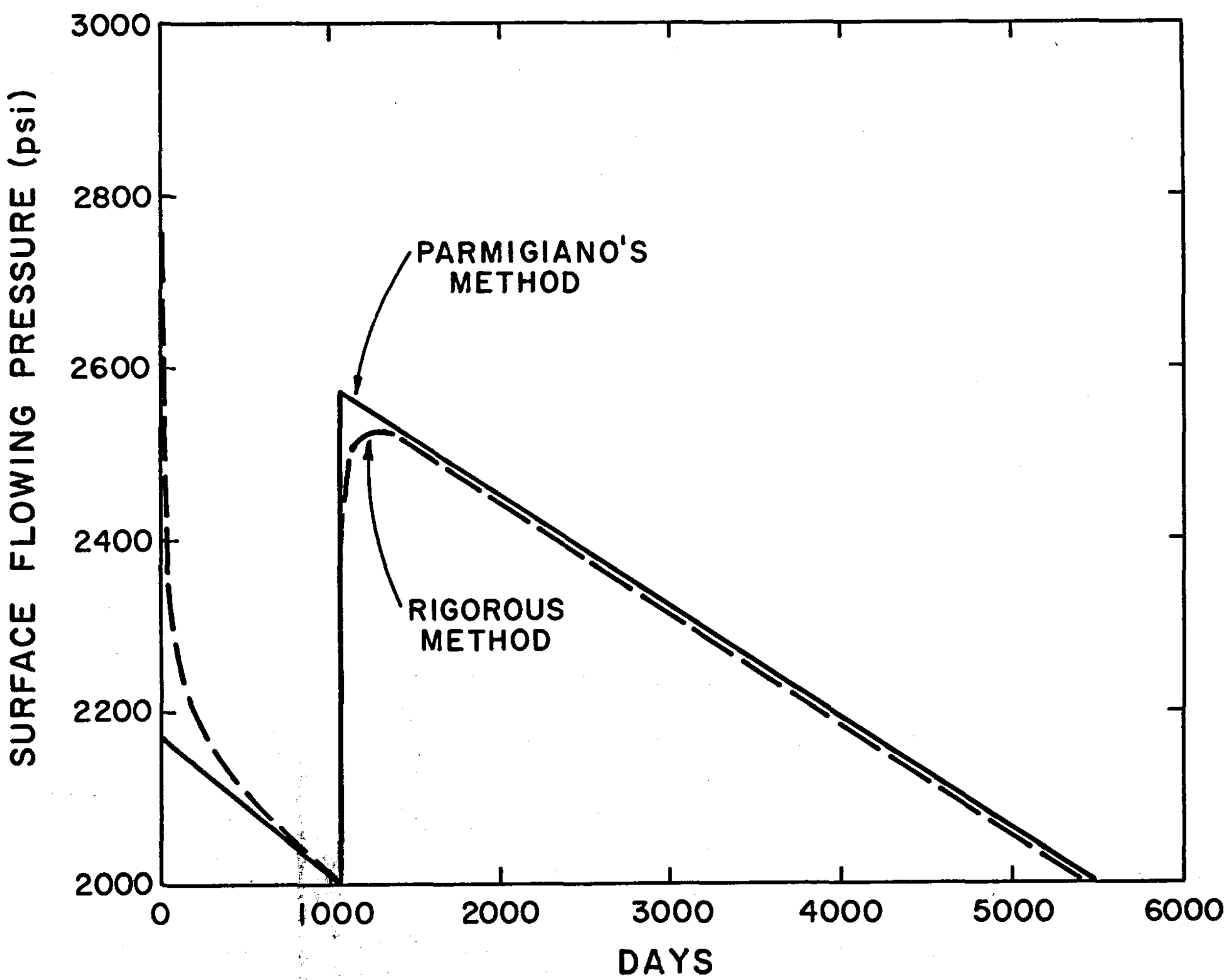

Figure 3. Surface-pressure history for hypothetical data.

CLUSTERED-WELL CASE

The clustered-well case consists of two or more wells located near the center of a bounded, circular aquifer. The rationale of this system is that a geohydraulic aquifer may be large enough to justify multiple wells, but the surface facilities dictate that the wells be in close proximity with each other.

A rigorous solution to this problem can be formulated along the lines of the rigorous method presented for the single-well case, namely the *Ei* solution. A large number of image wells are required for this solution, and computer useage is essential. Such a computer program is not available to the author, so this method will not be considered.

An approximate method, using the semi-steady-state equations discussed previously, has been developed and can be used with the same limiting assumptions used in the single-well case. Also, the wells must be in a relatively tight cluster, with all wells within a circle of radius equal to 0.1 or less of the external radius. All wells must produce at the same rate, q, and must be at equal distances from each other. Parmigiano (1973) developed equations for the two-, three-, and four-well cluster The reader is directed to his work for the derivations. The four-well cluster is shown in figure 4. The equation predicting the flowing tubing pressure of each well is

$$p_{tf} = p_i - \frac{q\mu}{7.08kh}\left(\ln \frac{r_e^4}{\sqrt{2}\, r_w d^3} - 3\right) - \frac{5.615Q}{\pi r_e^2 h\phi c_e} - \Delta p_f - \Delta p_h. \qquad (9)$$

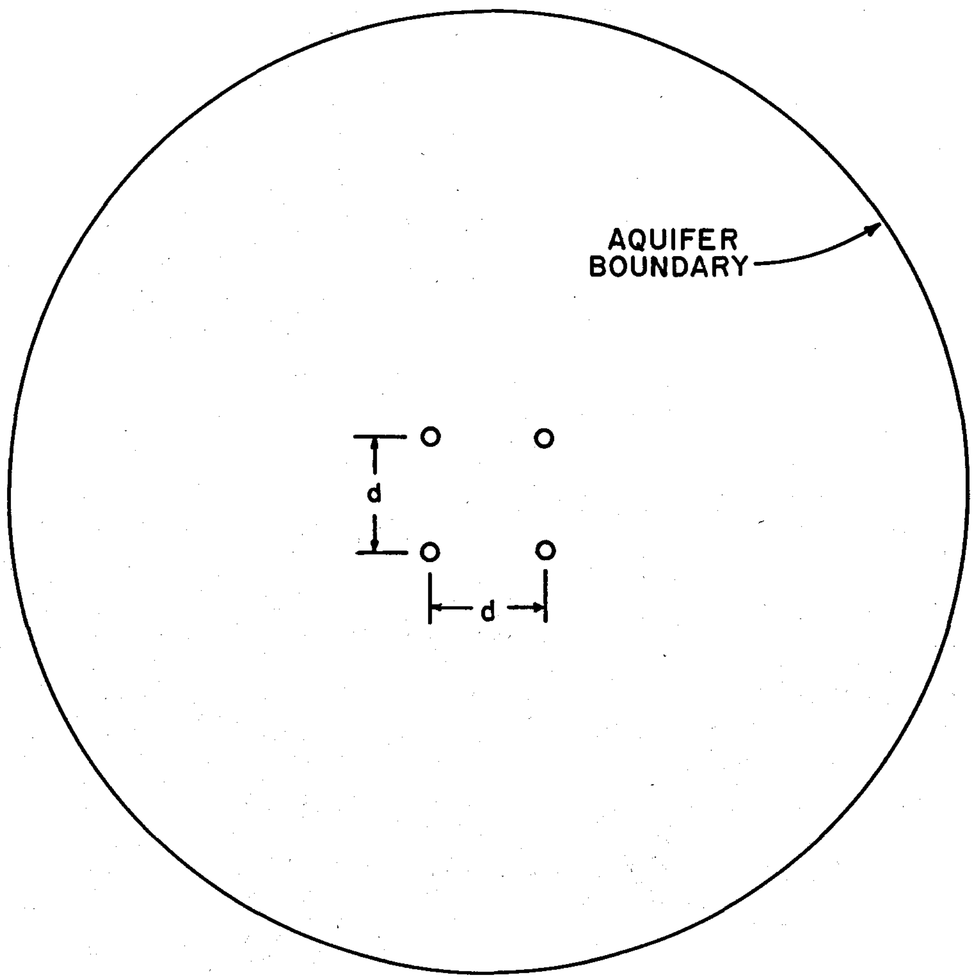

Figure 4. Four-well-cluster system.

Application of this equation points out that in a cluster of wells, each cannot deliver the same amount of energy to the surface as it could if it were alone in the aquifer. This is primarily due to interference of each well upon the others. It can be seen in equation 9 that as the distance between wells, *d*, gets smaller, the surface flowing pressure of each well decreases rapidly. The behavior of the clustered-well system can be summarized by stating that as the number of wells in the cluster increases, the energy-production rate for the aquifer increases, but the energy-production rate for each well decreases. Thus, there exists an economically optimum number of wells to exploit the aquifer.

Each well in the cluster can be compared to a standard well (a single well centered in the aquifer) by the use of the petroleum engineering concept (Craft and Hawkins, 1959) of the productivity ratio (*P.R.*).

$$P.R. = \frac{(q/\Delta p)_c}{(q/\Delta p)_s},$$

where the subscripts c and s signify the clustered well and the single well, respectively, and the Δp term signifies the darcy pressure drop due to flow through the reservoir, i.e., the first negative terms of equations 7 and 9. The effect of the number of wells in the cluster and the distance between wells on the P.R. of each clustered well is shown in figure 5 for the data of table 1.

EQUALLY SPACED WELLS

In the discussion of clustered wells it was noted that as the distance between the wells increases, the productivity ratio (the energy-producing rate) increases. Taking this to the limit, it can be surmised that the optimum well spacing in terms of energy-producing rates is where the wells are uniformly spaced throughout the aquifer. And indeed, if surface gathering systems and conversion facilities provide no obstacle, equally spaced wells will always be more desirable than clustered wells.

The calculation of the behavior of this system is very similar to the methods for the single-well system. For example suppose the 200,000-acre aquifer in the sample problem were developed with four uniformly spaced wells, as shown in figure 6. The prediction of the behavior of this system can be accomplished by the rigorous method displayed in the first example in this paper of the *single well in a bounded aquifer*. Each well behaves as though it were a single well in a 50,000-acre aquifer; four wells uniformly spaced in a square aquifer are exactly the same as four aquifers of one-fourth the size, each containing a single well.

Parmigiano's method for a single well in a bounded aquifer can also be used in this situation. The restriction that the aquifer shape has to be circular can be met by using a circle having the same area as the square aquifer (50,000 acres in this example). This procedure introduces only a small error in the results.

COMPLICATING FACTORS

The methods presented so far are valid or approximately valid for reasonably ideal systems, that is, systems having uniform permeability, porosity, and thickness. In addition, the sole driving force of the aquifer is its effective compressibility, namely, the sum of the water compressibility and the pore-volume compressibility.

Nonuniform Reservoir Parameters

The limitation of having uniform permeability, porosity, and thickness will probably not be a pertinent one. The aquifers will be penetrated by relatively few wells during exploration and exploitation (in comparison to an equivalently sized hydrocarbon accumulation). Therefore, data will not be available to accurately define the areal variations of these parameters.

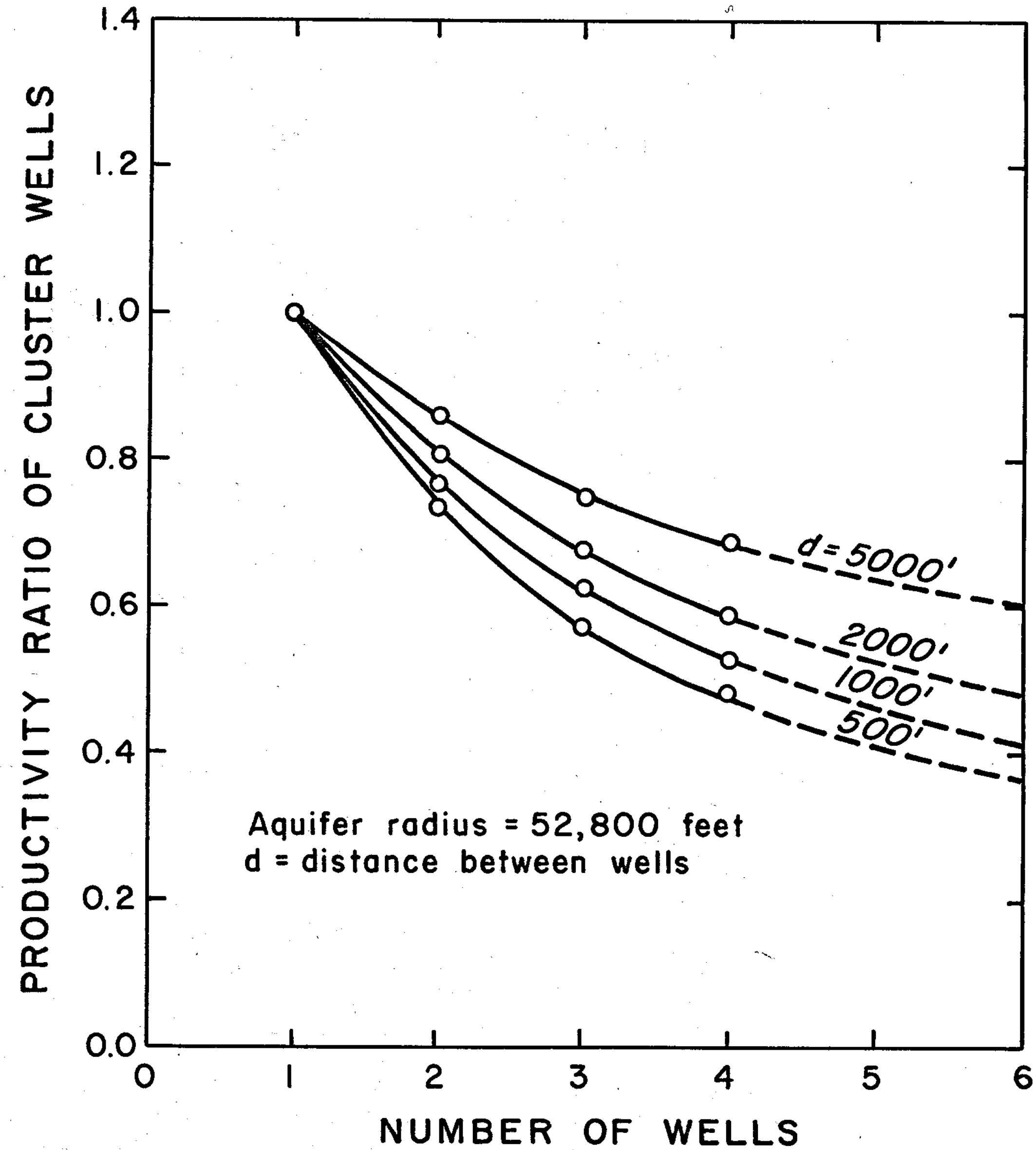

Figure 5. Productivity ratio of clustered wells.

Most likely, the use of constant values will be dictated by circumstance. If, however, data are available to define variations in parameters and if the variations are great, then numerical simulation of the aquifer similar to that in use for petroleum reservoirs will have to be used to predict aquifer behavior. The cost and complexity of the calculations will increase substantially over those of the simple methods presented in this paper.

Driving Force of the Aquifer

In the methods presented so far, it has been assumed that the sole driving force is the sum of the compressibilities of the water and the pore volume. Typically, water compressibility would be of the order of 3×10^{-6} psi^{-1} and rock compressibility would be of the order of 7×10^{-6} psi^{-1} (hence the value of 10×10^{-6} psi^{-1} used in the sample problem). Several other factors may contribute to the energy of a geopressured aquifer: (1) natural gas in

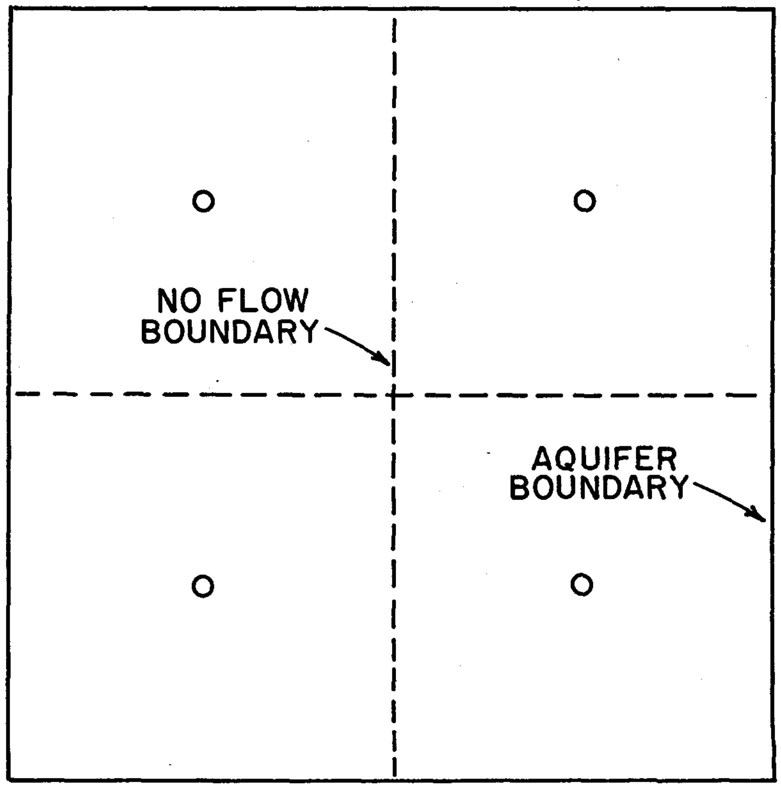

Figure 6. Uniformly spaced wells.

solution, (2) shale water, (3) abnormal rock compressibility, or (4) a gas reservoir in the aquifer.

If natural gas is in solution in the aquifer water, the water wells can be expected to produce natural gas. For the conditions set forth in the sample problem, fresh water at 10,000 psi and 300°F can hold as much as 40 standard cubic feet (SCF) per barrel according to data presented by Culberson and McKetta (1951). At a production rate of 100,000 barrels per day, this could represent a gas producing rate of 4,000,000 SCF per day, a very good gas well. This rate of gas production would probably never be realized because, as production began and pressures were reduced in the reservoir, much of the gas would come out of solution in the reservoir itself rather than be produced along with the water. This phenomenon, at first glance, might be thought to be quite beneficial because a developing gas phase in the reservoir could (1) migrate to some high position, where eventually a gas well could be drilled, and (2) increase the system compressibility (resulting in more energy production).

Unfortunately, little benefit will be realized from either of these effects. Suppose, for example, that all of the evolved solution gas of the sample problem remained in the reservoir to form a free-gas saturation. Suppose also that, at abandonment of the aquifer, the average reservoir pressure had fallen to 5,600 psi (hydrostatic head + 1,000 psi). The initial gas in solution is 40 SCF per barrel and the gas in solution at abandonment is 25 SCF per barrel. The amount of released gas is 15 SCF for every barrel of water originally in the aquifer. Using realistic compressibilities for the gas and the aquifer system, it can be shown that this amount of released gas would represent less than a 2-percent saturation. (Two-percent saturation is an optimistically high value because of the conditions set forth in this example). Such small gas saturations would exhibit very low (probably zero) relative permeability, hence migration of the gas would be negligible.

The effect of this small gas saturation on the overall system compressibility would also be small, but perhaps significant enough to warrant consideration. The greatest effect would occur near abandonment conditions, when the gas would exist at its lowest pressure and its correspondingly highest saturation and compressibility. The system compressibility would be

$$C_{avg} = C_g S_g + C_w S_w + C_f.$$

At an abandonment pressure of 5,600 psi, an assumed gas saturation of 2 percent, and ideal gas behavior, the compressibility would be

$$C_{avg} = \frac{1}{5,600}(0.02) + (3 \times 10^{-6})(0.98) + (7 \times 10^{-6})$$

$$= 13.5 \times 10^{-6}\,\text{psi}^{-1},$$

which represents a 35 percent increase over the system compressibility if gas is ignored. This is the effect only near abandonment conditions. At higher aquifer pressures, the gas saturation is smaller and the gas compressibility is lower, so the effect on the overall system compressibility is not as noticeable.

The effect of shale water is unknown at present. An often-quoted paper by Wallace (1969) indicates that water production from shales embedded in sand or surrounding sand was a significant source of energy in abnormally pressured gas reservoirs. However, many of his sample field cases seem to be explainable by normal water influx from aquifers. Although his paper elucidates the idea of shale water production, it has not been proven that this phenomenon is indeed a real one in all geopressured systems. A study by Bourgoyne and Hawkins (1972) shows mathematically that shale water might play a significant role in supplying energy to abnormally pressured systems. Whether this will be the case remains to be proven, and it awaits the exploitation and careful testing and monitoring of an abnormal aquifer.

It is suggested by Harville and Hawkins (1969) that rock compressibilities in abnormally pressured reservoirs are significantly greater than the rock compressibilities of normally pressured systems. Rock compressibilities of 30×10^{-6} psi^{-1} or higher have been indicated. If such high values do prove to be the case, energy production from geopressured systems will be considerably greater than previously thought. For the sample problem, an increase in rock compressibility of the magnitude suggested would result in over three times the energy production of that from an aquifer of normal rock compressibility. Effects of this magnitude call for additional work in the estimation of rock compressibility.

It has been reported (Geertsma, 1973) that surface subsidence is directly related to the formation thickness, depth, reduction in aquifer pressure, and rock compressibility. Abnormally high rock compressibilities might then result in abnormal surface subsidence. Geopressured aquifers are generally found at fairly great depth, and this will tend to offset the problem, however. Since subsidence is a potentially severe problem in the low-lying areas of South Louisiana, additional investigation will be necessary before exploitation of the geopressured resource can proceed in these areas.

The effect on aquifer behavior of a hydrocarbon reservoir, in particular a gas reservoir, existing in the aquifer is difficult to determine. The qualitative effect will be to increase the overall compressibility of the aquifer, thereby yielding increased energy production. The effect will primarily depend upon the distance to the hydrocarbon reservoir and its size.

WELL AND RESERVOIR TESTING

Standard petroleum engineering methods utilizing measured, flowing bottom-hole pressures are available for determining information about the wells and the reservoir. Probably one of the more useful tests will be the pressure-drawdown test, whereby a well is opened to flow while bottom-hole pressures are recorded. From this data, information such as reservoir permeability, reservoir size, well-bore damage, and barrier detection can be estimated. Matthews and Russell detail this and similar tests.

CONCLUSIONS

1. Established petroleum engineering methods are available for predicting the behavior of geopressured aquifers. These methods range in complexity from the simple hand-calculation-type to the complex computer-type solutions.
2. The effect of dissolved natural gas on aquifer behavior is small.
3. The effect of shale water as a pressure-support mechanism is still unresolved and warrants further work.
4. The amount of energy produced from a geopressured aquifer is highly dependent on rock compressibility. Further research into the possibility that abnormally pressured aquifers can be expected to have abnormally high rock compressibilities should be undertaken.

NOMENCLATURE

c = compressibility, psi
d = distance, feet
h = net sand thickness, feet
k = permeability, darcys
p_f = flowing bottom-hole pressure, psi
p_i = initial shut-in reservoir pressure, psi
p_{tf} = flowing tubing (or surface) pressure, psi
Q = cumulative water produced, barrels
q = water flow rate, barrels per day
r_e = external radius of aquifer, feet
r_w = well bore radius, feet
s_g = gas saturation, fraction
S_w = water saturation, fraction
t = time, days
t_s = readjustment (or stabilization) time, days
Δp_f = frictional pressure drop in tubing, psi
Δp_h = static head loss, psi
ϕ = porosity, fraction

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Discussion

Podio Thank you, Bill. We have a very busy schedule this morning, so I would like to limit the discussion now to just a couple of questions at this time.

Barnea
United Nations I would suggest that we first look at what we learned yesterday. I think we have three types of reservoirs; the shale, the geopressured zones with lower pressure, and (as shown in some of the tables of Dr. Jones's study) we see that in some of the regions we have geopressure zones of various types, one above the other.

Therefore, I believe the first approach is to look and see if we can find in an area geopressured zones of the different types which we might interconnect. If we find this situation, we have a totally new ball game. I do not know whether we have, today, adequate exploration experience that we can say what is the likelihood of finding, in a given area, shallow, medium-deep, and deep reservoirs which we could interconnect. But if we find two or perhaps even three which we could interconnect, we have a totally new situation, which would allow very many new reservoir management systems.

My question, therefore, is do we have experience that we may find in an area, shallow and medium or shallow and rather deep reservoirs which could be interconnected?

Bernard I can't answer that. I am not an exploration expert. Whether you have a giant sand or several smaller sands, I don't think it makes any difference at all.

Barnea Yes, it does. We saw that yesterday, very considerable differences in temperature, in pressure, and in salinity.

Bernard All right. But you give me four 50-foot sands and one 200-foot sand—

Barnea No, that isn't the decisive factor. The size is important, but the decisive factor is the difference in temperature, pressure, and salinity. And the salinity of fluid increases as the pressure changes.

If you could do it with one well, you'd have a very long life.

Dorfman Let me make a comment on this. I think, Dr. Barnea, if you'll hold off on this, we have a paper this afternoon being given by Palmer House that addresses this question.

Podio Is there another question?

Power
The University of Texas at Austin I have one question only. It refers to another hot-water program in Surprise Valley in California, where wells were drilled for information only and not for production purposes.

It seems that there are several means for producing super-hot water, but if the pressure is released when it reaches the surface, about 20 percent of the water will flash immediately to steam, which can be conducted to the turbines. This method is simple, but often wasteful since the residual hot water is either reinjected into the reservoir or otherwise disposed of. A more efficient system under present development employs the processing of the hot water through the heat exchanger thereby transferring the heat to isobutane, a liquid with a boiling point lower than that of water. Expanded greatly when heated, the isobutane emerges from the heat exchanger at a very high pressure, and, hence, is extremely efficient in driving a turbine. The water is then reinjected into the reservoir. This last statement is the one that I would like to get your advice on, repressuring, reinjecting the water instead of wasting it and so on. What effect would that have on your equations?

Bernard Well, of course, if you reinject the water, it seems to me that you're losing all of your hydraulic power, because it takes about the same amount to get it back in as it did to take it out which means, then, that what you're really doing is only recovering the thermal energy in the water itself.

The problems that I addressed myself to this morning were not concerned with the thermal but with the hydraulic. There is no way that you can inject to get the water out where you can come out ahead; you can't get something for nothing. The only way you're going to get the hydraulic end of it out is by natural pressure in the aquifer itself. If you have to inject or pump, forget it.

Podio Thank you, Bill. I'm sorry to cut off the discussion, but we do need to proceed. There will be time for further questions during the open discussion period at the end of this session.